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BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	ATMOS ENERGY CORPORATION'S AFFILIATE TRANSACTION AUDIT REVIEW/2005 RATE CASE	)) DOCKET NO. 20298-U)

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION STAFF

SEPTEMBER 29, 2005

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE: ATMOS ENERGY CORPORATION'S AFFILIATE TRANSACTION AUDIT REVIEW/2005 RATE CASE) DOCKET NO. 20298-U

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree from the University of Toledo. I also earned a Master of Business Administration degree from the University of Toledo. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than twenty-five years, both as an employee and as a consultant. Since 1986, I have been a consultant with J. Kennedy and Associates, Inc., providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions.

I have appeared as an expert witness on accounting, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on more than one hundred occasions. I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. I have testified in numerous proceedings before the Georgia Public Service Commission ("Commission"), including the last four Atlanta Gas Light Company ("AGLC") base rate proceedings in Docket Nos. 3780-U, 8390-U, 14311-U, and 18638-U. In addition, I have directed two audits on behalf of the Commission Staff of the affiliate transactions affecting AGLC and its costs for ratemaking purposes in Docket Nos. 13147-U and 14311-U. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am offering testimony on behalf of the Georgia Public Service Commission Adversary Staff ("Adversary Staff").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Adversary Staff's recommendation for the base revenue requirement and changes in the form of recovery between the base revenue requirement and various clauses (riders), including the revenue requirement effects of the Adversary Staff affiliate transaction and cost allocation audit of Atmos Energy Corporation ("AEC" or "Company") addressed in the panel testimony of Ms. Victoria Taylor and Lane Kollen, and to address various other specific revenue requirement issues.

Q. Please summarize your testimony.

A The Adversary Staff recommends a base rate reduction of $2,780,860 compared to the Company's revised request for a base rate increase of $4,189,037, which was revised upward from $4,022,723 to correct an error identified by the Adversary Staff. The following table provides a summary of the revenue requirement effects of the Adversary Staff recommendations.

ATMOS ENERGY CORPORATION - GEORGIA REVENUE REQUIREMENT
SUMMARY OF ADVERSARY STAFF RECOMMENDATIONS

Rate Base Issues		
Remove PRP Rate Base Components		(2,001,933)
Reduce CWC to Zero	$	(137,854)
Adjust Weighted Composite Factor to Oct 2005 Level		(110,826)
Further correct Weighted Composite Factor		(1,490)
Adjust Accumulated Depr for Lower Depreciation Expense		96,580
Correct ADIT State Income Tax Rate		(30,166)
Correct ADIT Errors in Rate Base		(342,250)
Adjust ADIT for Lower Depreciation Expense		(37,569)
Include Georgia Portion of Injuries & Damages Reserve		(7,319)
Operating Income Issues		
Remove PRP Operating Expenses (Net)		($126,008)
Add Back Bad Debt Expense on Gas Portion of Debt		$861,523
Modify Georgia Division Proposed Depreciation Rates		($769,660)
Reject Shared Services Proposed Depreciation Rates		($502,835)
Adjust SS Depr Expense & Other Taxes Based on October 2005 Composite Factor		($250,523)
Adjust SS Depr Expense & Other Taxes Based on Add'l Rev to Composite Factor		($3,237)
Adjust SS O&M Allocations Based on October 2005 Composite Factor		(617,969)
Adjust SS O&M Allocations Based on Add'l Revisions to Composite Factors		($13,072)
Reflect Productivity Gains in O&M Expenses		($355,890)
Reflect Productivity Gains in Other Taxes Expense		($12,247)
Reflect Savings from Consolidation of Mid-States President's Position		($27,700)
Remove Excessive AES Charges		($156,945)
Reflect Bad Debt Expense at 0.6% of Revenues		($564,723)
Modify Amortization of Rate Case Expenses		($40,000)
Reflect GTI Savings Produced		($119,000)
Adjust Uncollectible Accounts Expense for Change in Rev. Req.		($16,685)
Reduce Income Tax Expense for ITC Amortization		($81,506)
Rate of Return Issues		
Include Short Term Debt in Capital Structure		($491,736)
Revise Long Term Debt Rates		($30,631)
Reflect Return on Equity of 9.375%		($1,078,226)
Total Staff Adjustments to Revised Atmos Request		($6,969,897)
Less: Revised Atmos Requested Increase	$	(4,189,037)
Adversary Staff Recommended Change in Base Rates		($2,780,860)

The Adversary Staff base revenue requirement recommendation reflects several policy recommendations. First, we recommend that the Commission reject the Company's proposal to roll-in to base rates the Pipeline Replacement Program ("PRP") revenue requirement. This policy recommendation has the effect of reducing the Company's requested base rate increase by $2,127,941. However, under this Adversary Staff recommendation, the Company will continue to recover its PRP revenue requirement through the present PRP rider. Consequently, there will be no change in the status quo.

Second, the Adversary Staff recommends that the Commission reject the Company's proposal to reconstitute the present PRP surcharge rider as an alternative rate plan, which would utilize a formula based approach to provide annual base rate adjustments. This recommendation has no effect on the base revenue requirement in this proceeding and continues the PRP surcharge rider in its present form.

Third, the Adversary Staff recommends that the Commission reject the Company's request to include uncollectible accounts expense related to the gas commodity costs in the Purchased Gas Adjustment ("PGA") rider. This policy recommendation has the effect of increasing the Company's requested base rate increase by $861,523, based on the Company's adjustment to the historic year uncollectible accounts expense, although we recommend further adjustments to the test year uncollectible expense that are not due solely to this policy issue.

Fourth, the Adversary Staff recommends that the Commission accept the Company's request to modify the manner in which the franchise tax is computed and included in ratepayer bills. This policy recommendation has no effect on the Company's requested base rate increase because the franchise tax expense was removed by the Company from the base revenue requirement consistent with its request for this change in billing.

Fifth, the Adversary Staff recommends that the Commission accept the Company's proposal to include in base rates the existing amount of the margin loss recovery presently recovered through the rider and to reset the margin loss recovery rider factor to $0. This policy recommendation has no effect on the Company's requested base rate increase because the Company's proposal was reflected in its base rate increase request.

Sixth, the Adversary Staff recommends that the Commission accept the Company's proposal to change to a 60-day meter reading cycle, with the date modification of June through August as stated in the panel testimony of Ms. Jamie Barber and Mr. Michael J. McFadden, but only if the related operation and maintenance ("O&M") expense savings are reflected in the base revenue requirement. We have subsumed the savings from this change in our recommendation to reflect no escalation of O&M expense in the test year compared to the historic year.

In addition to these recommendations on various policy issues and the related effects on the base revenue requirement, the Adversary Staff recommends that the Commission incorporate the recommendations and the related effects on the revenue requirement of the Adversary Staff's affiliate and cost allocation audit, the specifics of which are addressed in the panel testimony of Ms. Victoria Taylor and Mr. Lane Kollen. These recommendations are reflected in the appropriate rate base, operating income, and rate of return sections of my testimony.

Finally, the Adversary Staff recommends that the Commission adopt numerous other recommendations affecting the base revenue requirement. I address most of these recommendations and other Adversary Staff witnesses address the remainder. More specifically, Mr. Stephen Hill addresses the return on common equity and Mr. Charlie King addresses depreciation rates and the related effects on depreciation expense.

I have structured my testimony to address first the policy issues in this proceeding associated with the base revenue requirement, followed by other issues separated into rate base, operating income, and rate of return issues, including the effects on those revenue requirement components of the Adversary Staff's affiliate and cost allocation audit.

II. POLICY ISSUES THAT AFFECT THE BASE REVENUE REQUIREMENT

<u>Company's Proposal to Roll-In to Base Rates the PRP Revenue Requirement and to Reconstitute the PRP as an Automatic Base Rate Adjustment Mechanism Should Be Rejected</u>

Q. Please describe the Company's PRP proposal.

A. There are two related components to the Company's PRP proposal. The first is the roll-in to base rates of the projected test year PRP revenue requirement. Thereafter, all pipeline replacement costs will be included in base rates. The PRP rider no longer will be utilized to recover PRP costs on an incremental revenue requirement basis.

The second component of the Company's PRP proposal is that it will retain the name of the PRP rider, but reconstitute it as an alternative rate plan. This alternative rate plan will result in annual adjustments to base rates, most likely rate increases throughout the duration of the pipeline replacement program. The annual adjustments to base rates will be based on the Company's computation of the revenue requirement for a projected test year, ostensibly reflecting the methodologies and types of ratemaking adjustments adopted by the Commission in this proceeding.

Q. What is the effect of the Company's PRP roll-in proposal on its base rate increase request?

A. The Company's PRP roll-in proposal constitutes $2,127,941 of its revised $4,189,037 base rate increase request, which is more than half its request in this proceeding. This amount was quantified by the Company in response to STF-S5-57, a copy of which has been replicated as my Exhibit___(LK-2).

Q. Should the Commission adopt the Company's PRP proposal?

A. No. First, the roll-in to base rates has the effect of unnecessarily increasing the Company's requested base rate increase because the PRP roll-in reflects a projected test year revenue requirement while the present PRP rider reflects a historic and, thus, a lower test year revenue requirement. The base revenue requirement is computed using a projected test year. However, the present PRP rider quantifies the revenue requirement for a historic period and then collects those amounts in arrears. As such, the Company's proposed base rate increase is greater than the sum of its non-PRP base rate increase and the PRP revenue requirement pursuant to the present PRP rider.

Second, the Company's proposal effectively would establish an alternative rate plan, without directly requesting such a plan in accordance with the statutory requirements of O.C.G.A. § 46-2-23.1. These statutory requirements include specific notice to its ratepayers and a demonstration that its proposed plan meets an entire litany of specific requirements. The Company did not publish the required notice or address the litany of specific requirements. In addition, the Company's witnesses claimed at the hearing on the Company's Direct Testimony that the Company was not seeking to have its rates determined pursuant to an alternative rate plan.

Third, the Company's proposal will require that it annually develop a projected test year revenue requirement comparable to its filing in this proceeding and further will require that the Staff review this revenue requirement on an expedited basis each year. This would be a substantial undertaking for both the Company and the Staff, comparable to an annual rate filing in most respects. Such filings would be far more complicated and the Staff review necessarily far more involved than is the case with the present PRP.

Fourth, the use of a projected test year necessarily involves the selection and application of numerous assumptions, at least some of which the Commission could not reasonably anticipate or preemptively affirm in this proceeding. Such assumptions would not be subject to the same level of review or challenge by the Adversary Staff or intervenors that presently is available under the existing base ratemaking process.

Fifth, the projections based on such assumptions would never be trued-up to actual. Such a structure would create an inherent incentive for the Company to underestimate projected revenues and overestimate projected costs each year.

Sixth, the Company's proposal is not sufficiently developed. The Company's proposal does not identify, describe, or provide the schedules and workpapers that would be required to implement such a plan. At a minimum, such a plan would require an annual filing that provides the same information that is currently provided in the Commission's Minimum Filing Requirements.

Q. If the Company's PRP proposal is rejected, as you recommend, will the Company continue to recover its pipeline replacement costs pursuant to the present PRP rider?

A. Yes. The Company will recover its pipeline replacement costs in the same manner as it presently does. The present PRP rider will remain unchanged. As such, if the Company's PRP proposal is rejected, it simply maintains the status quo and the Company is not harmed in the least.

<u>**Company's Proposal to Shift Uncollectible Accounts Expense Related to Gas from Base Rates to PGA Should Be Rejected**</u>

Q. Please describe the Company's proposal to shift uncollectible accounts expense related to gas from base rates to the purchased gas adjustment rider.

A. The Company proposes to change the recovery of the uncollectible accounts expense related to gas from the base revenue requirement to recovery through the PGA rider.

Q. What is the effect of the Company's proposal on its base rate increase request?

A. In accordance with its proposal, the Company removed $861,523 in expense from the base revenue requirement. However, if the Company's proposal is adopted, the PGA rates would increase by an amount equivalent to the amount removed from the base revenue requirement.

Thus, there would be a PGA rate increase in addition to the Company's base rate increase request. After the initial PGA rate increase, the amount recovered through the PGA rider would vary based on the Company's actual uncollectible accounts expense.

Q. Should the Commission reject the Company's proposal to shift uncollectible accounts expense related to gas from base rates to the PGA?

A. Yes. First, the Commission already has ruled that such costs are not "purchased gas costs" as defined in O.C.G.A. § 46-2-26.5(a)(7). In Docket No. 14105-U, the Company filed an Amendment to 2001-2002 Gas Supply Plan and filed testimony to recover delinquencies incurred as a result of a Commission ordered moratorium on termination of service to firm customers. In that docket, the Adversary Staff filed a Motion to Strike and argued that "the delinquencies that the Company seeks to recover represent bad debt" and argued that such costs were not recoverable pursuant to the PGA statute. In response to an Adversary Staff Motion, the Commission struck both the Amendment and the testimony "for the reasons set forth in Adversary Staff's motion."

Second, the Company has not defined how it proposes to compute the actual uncollectibles expense that it would recover through the PGA. As such, it is not clear whether the expense would be the actual writeoff amounts recovered in arrears, projected writeoff amounts, or an expense accrual, and if an expense accrual, on what basis it would be quantified and trued-up in future PGA filings, if at all.

Company's Proposal to Roll-In and Reset to $0 the Margin Loss Recovery Rider Should Be Adopted

Q. Please describe the Company's proposal to roll-in and reset to $0 the Margin Loss Recovery Rider.

A. The Company proposes to retain the Margin Loss Recovery rider, but to reset the initial factor to $0. The rider would continue to operate as it has in the past, with incremental margin losses subsequent to the effective date of rates in this proceeding recovered through the rider and reflected in the factor.

Q. Should the Commission adopt the Company's proposal to retain and reset the Margin Loss Recovery rider to $0?

A. Yes. There is no reason to change the status quo regarding recovery of lost margins through this rider. However, the actual losses projected for the test year are reflected in the Company's base revenue requirement. Consequently, it is necessary to reset the margin loss recovery rider to $0 so that the test year margin losses are recovered only once.

III. BASE REVENUE REQUIREMENT – RATE BASE ISSUES

Cash Working Capital Should Be Set at $0 In Absence of Lead/Lag Study

Q. Please describe the Company's request for a cash working capital allowance in rate base.

A. The Company included cash working capital ("CWC") of $1,089,261 in rate base, which it computed using the one-eighth O&M expense formula. The Company did not perform a lead lag study. In fact, according to the Company's response to STF-5-28, the most recent lead lag study AEC has performed was for its Colorado jurisdiction dating back to 2000.

Q. Is the Company's request for a CWC allowance in rate base consistent with the Commission's Order in Docket No. 6691-U?

A. No. The Commission rejected the Company's request to use the one-eighth O&M expense methodology in its 1996 rate proceeding. Instead, the Commission used a one-eighteenth of O&M expense methodology (see Findings of Fact 2.D). The Commission adopted this method only because a lead/lag study had not been performed. The same findings of fact stated "The Commission has stated previously its preference for a lead –lag study. In fact, Mr. Smith recommended that, in this docket ~~Docket No. 6691-U~~, the Company should move toward the use of the lead-lag approach in future proceedings".

Q. In its recent base rate proceeding in Virginia, in Case No. PUE-2003-00507, did the Company include a CWC allowance in rate base contingent on the one-eighth formula?

A. No. In that proceeding, the Company requested a $0 CWC allowance in rate base. That case was settled by the parties. Given that the settlement in that proceeding was for a fraction of the Company's requested increase, it is reasonable to conclude that the settlement did not provide the Company with a CWC allowance greater than the $0 it requested.

Q. Should the Commission approve a CWC allowance in rate base above $0 in this proceeding?

A. No. First, the Company has provided no evidence that a positive CWC balance is appropriate. The Company has not performed a lead/lag study for this or any other jurisdictions in recent years and has no apparent intention of doing so. Second, a properly developed lead/lag study would likely produce a negative balance or at least no more than $0. Apparently, this was the conclusion reached by the Company in its $0 CWC request in the Virginia case mentioned above. Third, in Docket No. 6691-U, the Commission reiterated its desire for a lead/lag study to properly set the CWC balance. The Company ignored the Commissions request when filing for its rate increase in this proceeding.

Q. If the Commission decides to use the one-eighteenth method for determining the CWC balance in this proceeding, will any further adjustments need to be made to the Company's request?

A. Yes, if the one-eighteenth formula is adopted, an adjustment will need to be made corresponding to any approved adjustments related to the level of test year O&M expenses.

Q. What is the effect on the Company's proposed revenue requirement of your recommendation to set the CWC at $0 in the absence of a lead/lag study?

A. The effect is to reduce the Company's proposed revenue requirement by $137,854. I computed this amount by multiplying the Company's requested CWC amount of $1,089,261 by the Company's requested grossed-up rate of return of 12.66%.

<u>Accumulated Deferred Income Taxes Should Be Reduced to Reflect Georgia State Income Tax Rate</u>

Q. Please describe how the Company quantified the accumulated deferred income taxes net liability amount that it subtracted from rate base.

A. Accumulated deferred income taxes ("ADIT") amounts are the result of temporary differences, which are defined as differences in revenues and expenses between tax and book accounting, usually due to timing differences. The Company utilized the temporary differences from the AEC Shared Services division, Mid-States Operating Division, Eastern Regional Office, and directly assigned to Georgia and multiplied those temporary differences times the 35% income tax rate for federal ADIT and times a generic 3% state income tax rate for state ADIT. Thus, the ADIT amounts reflected in the Company's filing assume a combined federal and state income tax rate of 38.00%.

Q. Is the use of a combined federal and state income tax rate of 38.00% correct?

A. No. The combined federal and state income tax rate in Georgia is 38.90%, a tax rate which the Company otherwise used in its filing to determine the income taxes included in operating income. The use of the 38.00% income tax rate to compute the ADIT amount had the effect of understating the ADIT net liability amount and thus, overstated rate base and the revenue requirement.

Q. Have you quantified the effect of using the correct 38.90% income tax rate to compute ADIT on the Company's proposed revenue requirement?

A. Yes. It reduces the Company's proposed revenue requirement by $30,166. The Company's rate base was overstated and the ADIT understated by $238,354. The rate base effect was computed by using the ADIT net liability, corrected for the error acknowledged by the Company, of $10,063,815, divided by 38.00% and then multiplied by 38.90%. To compute the revenue requirement effect, the change in rate base was multiplied by the Company's requested grossed-up rate of return.

<u>Accumulated Deferred Income Taxes Should Be Reduced to Remove ADIT Asset for Deferred Gas Costs</u>

Q. Why should the Commission exclude the ADIT asset for deferred gas costs from rate base?

A. First, this amount should be set at a normalized amount of $0 for the test year. An amount of $0 assumes that there is neither an overrecovery nor an underrecovery through the PGA. By contrast, the Company simply assumed that it would be in an underrecovery situation in the test year. This is an invalid assumption and one that the Company has not supported through testimony or in response to discovery. Second, the amount reflected by the Company as an increase to rate base is the December 31, 2004 balance, an amount that certainly is not valid for the test year.

Q. Have you quantified the effect on the Company's proposed revenue requirement of removing the ADIT asset for deferred gas costs?

A. Yes. The effect is to reduce the revenue requirement by $117,813. This amount was computed by multiplying the rate base amount of $930,898 by the Company's requested grossed-up rate of return of 12.66%.

Injuries and Damages Reserve Should Be Subtracted From Rate Base

Q. Please describe the Company's treatment of injuries and damages expense and the related reserve in the base revenue requirement.

A. The Shared Services division accrues injuries and damages ("I&D") expense, which then is allocated through the Mid-States Operating division to Georgia and included in the Company's revenue requirement. However, the Company did not use the I&D reserve balance to reduce rate base.

The Company accrues these expenses and adds them to the I&D reserve, for the purpose of smoothing the financial impact of unexpected and large I&D losses (see responses to STF-5-20 and STF-5-21) The expense accruals are added to the Injuries and Damages reserve and actual losses are subtracted from the reserve. If there is a reserve balance, it means that the expenses that have been accrued exceed the actual payments for I&D losses.

Q. Has the Commission already determined that it is necessary to reduce rate base by the I&D reserve?

A. Yes. In Docket No. 6691-U, the Commission determined that it was necessary to reduce rate base by the I&D reserve. The Commission's Order described this reserve balance as "ratepayer – contributed capital to the Company, on which a return should not be earned" and made an adjustment to reduce rate base for the Company's I&D reserve.

Q. Should the Commission reduce rate base by the amount of the I&D reserve?

A. Yes. First, the reserve amount reflects recovery from ratepayers in excess of the amounts paid out for I&D losses. As such, the ratepayers are entitled to a rate of return on these funds. Second, the Commission already has determined that the Company should subtract the I&D reserve from rate base. The Company does not object to this requirement; it simply did not reflect a reduction to rate base for this amount in its filing.

Q. Have you quantified the revenue requirement effect of this Injuries & Damages reserve reduction to rate base?

A. Yes. The revenue requirement should be reduced by $7,319. Rate base for the test year should be reduced by $57,828. To compute the rate base effect, Adversary Staff utilized the December 2004 AEC Shared Service division I&D reserve balance, which was then multiplied by the Adversary Staff's recommended AEC Shared Services division Georgia rate base allocation factor of 2.25%. The AEC Shared Services division I&D liability reserve balance at December 31, 2004 was $2,570,150, according to the Company's response to STF-5-20.

<u>AEC and Mid-States Rate Base Amounts Allocated to Georgia Should Reflect Adversary Staff Recommendations on Affiliate Transactions and Cost Allocations</u>

Q. Have you reflected the changes to the AEC and Mid-States rate base amounts allocated to Georgia consistent with the Adversary Staff recommendations on affiliate transactions and cost allocations?

A. Yes. These changes are reflected in the Adversary Staff revenue requirement recommendation in the Summary section of my testimony. AEC rate base amounts have been reduced for plant in service, accumulated depreciation, ADIT, CWIP, materials and supplies, and prepayments allocated to Georgia to reflect the Adversary Staff recommendations to 1) revise the AEC allocation factors to reflect known and measurable changes, 2) to correct the erroneous selection of AEC allocation factors, 3) correct ADIT errors, and 4) to reflect the effects on accumulated depreciation and ADIT of Mr. King's recommendations on the AEC shared services depreciation rates and expense. The computations of these amounts are detailed in the separate Panel Testimony of Ms. Taylor and Mr. Kollen on Affiliate Transactions and Cost Allocation issues.

IV. OPERATING INCOME ISSUES

Uncollectible Accounts Expense Should Reflect Reasonable Amount for Test Year

Q. Please describe the amount of uncollectible accounts expense included by the Company in the test year.

A. The Company included $1,069,511 in uncollectible accounts expense, of which it proposes to recover $207,988 through base rates and $861,523, based on the historic year gas revenues, through the PGA. The Company quantified the $207,988 test year amount by escalating the historic year amount for inflation and further increasing that amount based on the proposed base rate increase.

Q. Please describe how the Adversary Staff's recommendation to reject the Company's proposal to include uncollectible accounts expense for gas revenues in the PGA affects the amount included for recovery in base rates.

A. If the Commission rejects the Company's proposal to recover the gas portion of uncollectible accounts expense through the PGA, then the entirety of the uncollectible accounts expense determined to be reasonable must be recovered through base rates.

Q. Is the Company's requested amount of uncollectible accounts expense reasonable?

A. No. The total amount of uncollectible accounts expense is excessive for several reasons. First, the uncollectible accounts expense in the 2004 historic year is excessive and cannot form a reasonable basis for the test year expense. The Company's test year amount is based on the historic test year, which included an abnormally high amount of uncollectible accounts expense booked in part to eliminate a reserve deficiency caused by huge writeoffs in 2001, according to Schedule B-7 of the Company's filing. The actual writeoffs in fiscal year 2004 were $792,167 compared to the uncollectible accounts expense of $3,571,337. The actual writeoffs in calendar year 2004 were $500,452 compared to the uncollectibles accounts expense of $1,022,932, which the Company escalated for the test year after removing the portion it allocated to gas costs.

Second, the total uncollectible accounts expense requested by the Company for the test year is approximately 1.5% of total revenues, far in excess of the actual writeoffs over the last several years. The actual writeoffs in Georgia averaged 0.59% of total revenues for the last fiscal year through June 2005, reflecting a downward trend line compared to prior fiscal years. Actual writeoffs in Georgia in fiscal year 2004 were 1.18% of total revenues, in calendar year 2004 were 0.72%, and in fiscal year 2005 through June actually were a negative 0.1%.

Third, AEC has focused on uncollectible accounts expense throughout its utility jurisdictions over the past several years with the objective of reducing this expense. Graphics from an August 9, 2005 conference call with analysts to review third quarter 2005 financial results indicate that uncollectible accounts expense for all utilities was 0.83% of total revenues for fiscal year 2003, 0.29% of total revenues for fiscal year 2004 and 0.52% of total revenues for fiscal year 2005 year to date. In a November 10, 2004 conference call with analysts to review fiscal year 2004 financial results, Robert Best, the Chairman, CEO, and President of AEC, told participants that "Our collection efforts have been successful in reducing bad debt expense and our allowance for doubtful accounts is back well within our historical range."

Q. What is a reasonable level of uncollectible accounts expense for the test year?

A. A reasonable level of uncollectible accounts expense for the test year is $504,788, which reflects a 0.6% uncollectible accounts expense to total revenues ratio. Recognizing that this is a matter of judgment, the Adversary Staff utilized the high end of a 0.30% - 0.60% reasonable range. In addition, we applied this 0.60% uncollectible accounts expense to total revenues, which reflects the Company's projection of base revenues in the test year and my projection of higher PGA revenues in the test year compared to the historic year. To project the test year gas revenues for this purpose, we relied on the test year gas prices used by the Company to project the storage gas amounts included in rate base as reflected on its WP D1b-6 and supporting workpapers, which were significantly higher than actual gas prices in the historic year.

Q. How did you compute the amount of the adjustment to the revenue requirement to reflect the reasonable level of uncollectible accounts expense that you recommend?

A. The Adversary Staff subtracted the amount of the Company's request of $1,069,511, which includes the amount the Company proposes be recovered through the PGA, from the $504,788 reasonable level of uncollectible accounts expense that we recommend.

Q. Have you also included a separate adjustment to reduce uncollectible accounts expense consistent with the Adversary Staff's recommendation to reduce base revenues?

A. Yes. We used the same 0.60% uncollectible accounts expense to total revenues to quantify this adjustment.

<u>Rate Case Expense Should be Amortized Over Five Years</u>

Q. Please describe the Company's request for amortization of the costs of this proceeding.

A. The Company has included $100,000 in rate case amortization expense in its proposed revenue requirement. The Company projects that it will incur $300,000 in costs for this rate proceeding and proposes to defer and amortize this amount over 3 years.

Q. Should the Commission use a three year amortization period?

A. No. The Adversary Staff recommends that the Commission use a five year amortization period. Although the timing of the Company's next base rate proceeding cannot be predicted with certainty, it has been nearly ten years since the Company's last base rate proceeding. If the Commission uses a three year amortization period and authorizes the Company to collect $100,000 annually, the Company would collect $1,000,000 to recover $300,000 if another ten years passes before its next base rate proceeding. If instead, the Company files another base rate proceeding within the next five years, then the Commission can ensure that the Company still recovers the remaining unamortized amount of these deferred costs in that subsequent proceeding. As such, the Company will not be harmed by using a five year amortization period instead of its proposed three years.

Q. Have you quantified the effect of your five year amortization period recommendation?

A. Yes. The use of a five year amortization period will reduce the Company's rate case amortization expense and its revenue requirement by $40,000.

<u>GTI Research and Development Expense and Related Savings Should be Reflected in Revenue Requirement Subject to Actual Funding and Selection of Cost-Effective Projects</u>

Q. Please describe the GTI "surcharge" that the Company has included in the base revenue requirement.

A. The Company proposes that the Commission authorize a "surcharge" of $119,000 to fund research and development ("R&D") through the Gas Technology Institute ("GTI"). However, instead of a typical surcharge, the Company has included this amount as an O&M expense included in the base revenue requirement. In other words, the Company's surcharge proposal is a misnomer; there is no surcharge proposal.

The requested amount ostensibly represents an annual pledge amount to GTI to help fund further R&D efforts that are intended to benefit gas consumers through lower utility costs and other "gas consumer benefits." GTI Director of State Regulatory Programs, Ronald Edelstein, defined "gas consumer benefits R&D" in his Direct Testimony as "a specific type of R&D, in which the applicable technologies result in benefits that primarily accrue to gas consumers. These benefits include lower energy use (through increased-efficiency appliances), increased safety, enhanced deliverability, and reduced energy costs (through lowering of gas local distribution company operating and maintenance-O&M—costs)."

Q. If the Commission approves the GTI expense recovery in the base revenue requirement, is there any guarantee that the money will be spent on projects applicable to Georgia ratepayers or even at all?

A. No. There is no guarantee that any GTI surcharge will be used to fund GTI projects or, for that matter, used to fund any R&D projects. Consequently, if the Commission authorizes recovery of this amount for R&D to benefit ratepayers, then it should require that the Company actually use the amount it recovers for this purpose.

Q. Has the Company reflected any projected cost savings in its test year filing related to these GTI commitments?

A. No. Yet one of the primary benefits identified by Mr. Edelstein of the GTI R&D projects is a reduction in O&M expense for the sponsoring utility. Mr. Edelstein claims that GTI's benefit-to-cost ratio in recent years is 8:1 (Edelstein Direct at 8). He also states, "Based on our twenty-year track record of maintaining benefit-cost ratios of over 8:1, I believe that in the future GTI can sustain this benefit-to-cost ratio for Georgia gas consumers." In fact, at hearing, Mr. Edelstein confirmed that there would be such savings to the distribution utility's customers ranging from a 4:1 ratio to an 8:1 ratio. (Tr. at 373-374). Although these overall benefits include measures that could reduce overall demand for gas and result in lower revenues from ratepayers in that manner, it is reasonable to expect that O&M costs also will decrease by at least the amount of the R&D expense, thus reflecting at least a 1:1 ratio for such savings.

Q. Should the Commission authorize the recovery of GTI research and development expense through base rates?

A. Yes. The Company has made a compelling case for the value of such R&D, and more specifically, for the cost savings that it expects to achieve as the result of its participation in this research. However, in addition to the cost of the GTI R&D, the Commission should recognize the O&M expense savings from that research. These savings should inure to ratepayers. The Commission also should require that amounts collected for such research actually are expended for that purpose.

Q. Why should the Commission recognize the cost savings resulting from the investment in research and development made on behalf of the Company's ratepayers?

A. As a practical matter, the savings in O&M expense should exceed the cost of the GTI R&D. The Company agrees that such savings should benefit ratepayers. Thus, it is reasonable to include a reduction to O&M expense equivalent to the amount of the GTI R&D expense.

<u>**Depreciation Rates Proposed by Company Should be Replaced with Adversary Staff Recommendations**</u>

Q. Have you reflected the depreciation rates recommended by Mr. King in the Adversary Staff's recommended base revenue requirement?

A. Yes. Mr. King provided the effect on test year depreciation expense if his depreciation rates are adopted. This was compared to the depreciation expense included by the Company in its filing based on its proposed depreciation rates. This includes the effects of his recommendations on both AEC Shared Services plant allocated to Georgia and on Georgia directly assigned plant.

$123,422 adjust

We have adjusted Mr. King's quantification to reflect the Adversary Staff policy recommendation on the PRP roll-in. This reduction in Mr. King's quantification removes the effect of his recommendation on the PRP plant depreciation expense. This adjustment was necessary because the Adversary Staff has removed the PRP plant from rate base consistent with its recommendation not to roll-in the PRP to base rates. Of course, under the Adversary Staff recommendation, Mr. King's depreciation expense recommendations would be reflected in the PRP depreciation expense computation going forward.

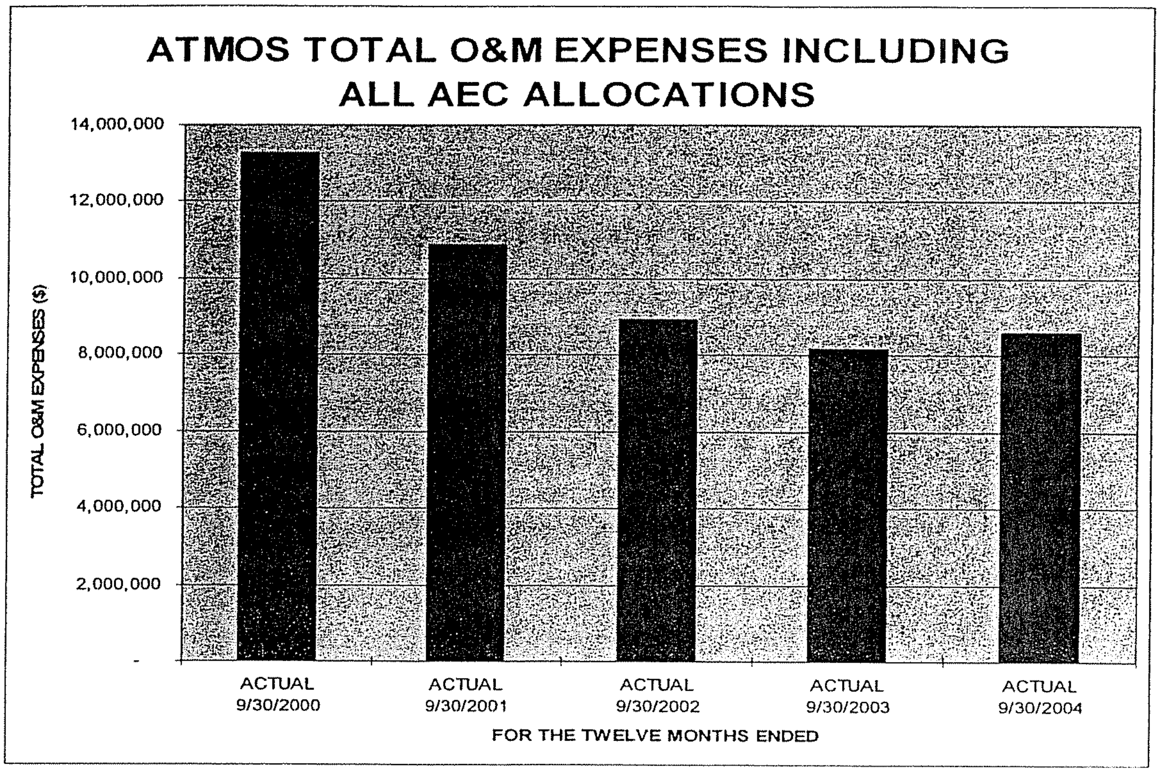
<u>O&M Expense Should Reflect Productivity Improvements Due to Technology Investments and Process Efficiencies</u>

Q. Please describe how the Company projected other operation and maintenance expenses included in the projected test year.

A. The Company projected most of the other operation and maintenance ("O&M") expenses included in the projected test year by applying various inflation rates, based on the Consumer Price Index ("CPI"), to historic test year amounts. These expenses include those incurred directly in Georgia and those allocated to Georgia from the AEC Shared Services division, the Mid-States Operating division, and the Eastern Regional Office. The Company included an increase in O&M expense of $355,890 and an increase to other taxes expense of $12,247, with a combined revenue requirement effect of $368,137, for CPI-based inflation utilizing this methodology. This quantification excludes all effects on uncollectible accounts expense, which I previously discussed, and benefits expense, which the Company based on recent actuarial studies and non-CPI based escalation factors.

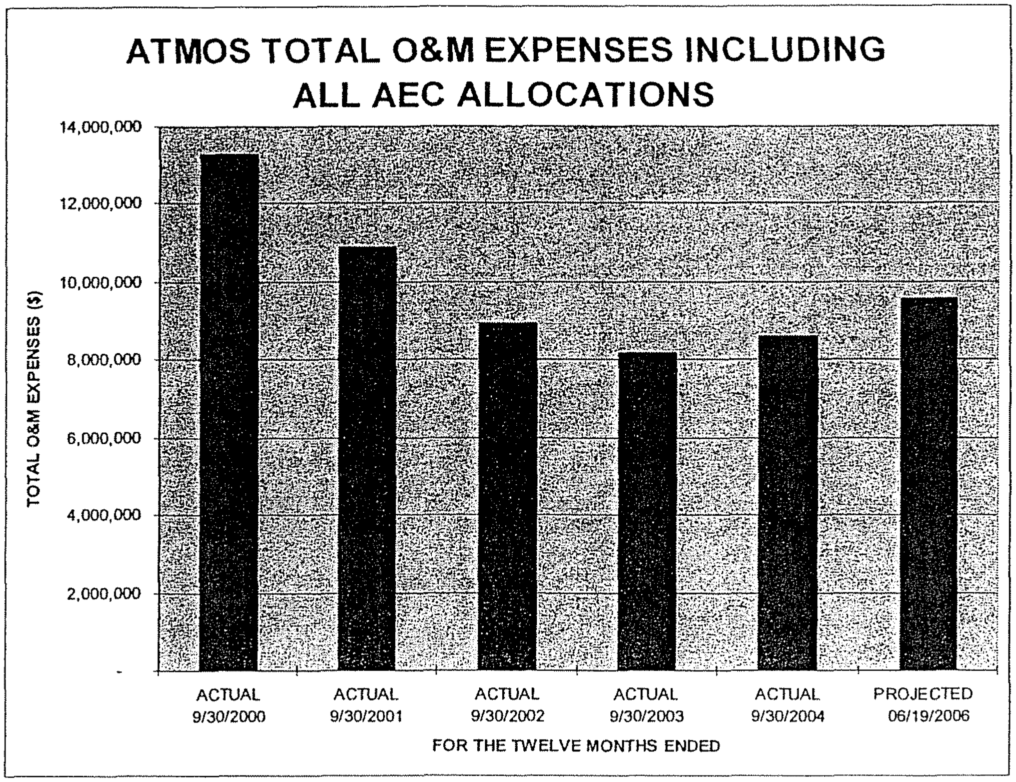
Q. Is it reasonable to project the O&M expenses for the test year in this manner?

A. No. This methodology completely ignores the reality of AEC's demonstrated ability to control cost growth in its utility operations, primarily through productivity gains achieved through investment in technology and other process improvement. The following chart demonstrates AEC's success in controlling the growth in total O&M expenses, which includes payroll, pension, OPEB, and group insurance expense.



Q. How does the Company's projected O&M expense included in its filing compare to its actual O&M expense for the last five years?

A. The Company's projected O&M expense included in its filing, adjusted to include the uncollectible expense the Company removed in conjunction with its proposal to recover such costs through the PGA, is significantly in excess of its actual O&M expenses for the last four years. The following chart compares the Company's actual O&M expense for the last five years to its request in this proceeding.



The historic information was obtained from the Company's response to STF-5-5, adjusted to remove the amounts in account 921, which, except for relatively minor amounts, reflected certain merger amortization expenses. The Adversary Staff obtained the test year information from the Company's filing and increased the uncollectible accounts expense for the amount of expense removed by the Company in conjunction with its proposal to recover these costs through the PGA rather than base rates. These adjustments were necessary to ensure consistency between the historic and test year data for comparative purposes.

Q. How has the Company successfully achieved almost no growth in its actual O&M expenses, despite inflation pressures and other specific cost increases in expenses such as pension expense, OPEB expense, and group insurance expense?

A. The Company has controlled its costs through a focus on cost control, including the adoption of best practices within the industry and the investment in and implementation of technology to improve productivity. Improvements in productivity allow the Company to use fewer resources to accomplish required activities. Investments in technology from 2004 through the test year include satellite-based mobile data terminals for service technicians, an automated invoice processing system, an upgrade to the customer billing system, a new accounts receivable module to enhance collection activities, a new plant accounting system, and a new construction asset management system. These investments, their costs, and projected benefits are described in greater detail in the Company's response to STF-5-13, a copy of which has been replicated as my Exhibit___(LK-3).

The Company considers the investment in and implementation of technology to be an important component of its strategy of controlling costs. The Company's use of technology to drive increases in productivity and achieve reductions in costs is prominently featured in AEC presentations to securities analysts.

The President of the Mid-States Operating division, Mr. Paris, confirmed at the hearing on the Company's direct case, that the Company invested in technology to achieve productivity improvements, or efficiencies. The following exchange took place between the Adversary Staff attorney and Mr. Paris at that hearing. (page 39 line 14 – page 40 line 2)

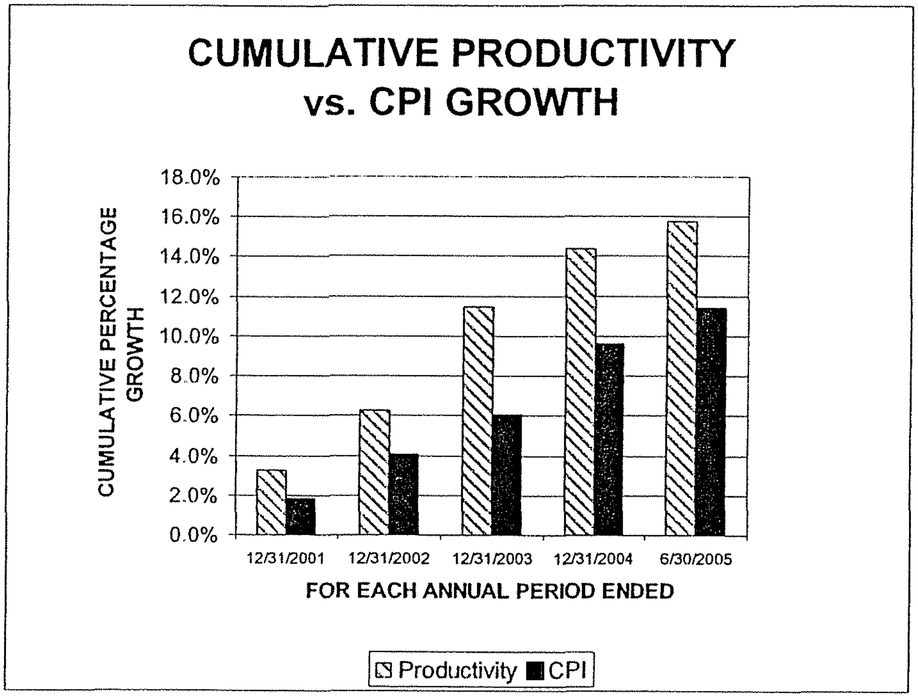
Q Now would you agree, Mr. Paris, that one of the ways the company has controlled costs in recent years has been through various technology based incentives?
A We've invested in technology -- I don't know about technology incentives. We've invested in technology which has made us more efficient.

Q Okay, but incentives from the technology that's available?
A Sure, okay.

Q And this investment in the technology, is your opinion that it is done so to achieve savings in operation and maintenance expenses, one of the goals?
A It's been one of the reasons we've invested in that technology, yes.

Q. How do the Company's efforts to improve productivity and control growth in O&M expenses compare to national averages in productivity improvement?

A. In recent years, there has been a surge in productivity as reflected in the nonfarm productivity measure published by the U.S. Bureau of Labor Statistics. This productivity growth has more than offset cost escalations as measured by the CPI, the same measure used by the Company to project its test year O&M expenses compared to historic test year levels. The following chart compares cumulative productivity growth by year to inflation growth as measured by the CPI since 2001.



Based on national productivity experience compared to CPI inflation, there should be no increase in the Company's projected test year O&M expense compared to the historic year, excluding such costs as employee benefits. This conclusion is consistent with the Company's actual experience as I previously demonstrated.

Q. Has the Company included all of its actual and projected test year investments in technology to improve productivity in rate base in its filing?

A. Yes. This is a critical point as well. If the ratepayers pay for the technology to drive the productivity improvements, then they should receive the benefits of the attendant cost reductions. The Company's filing reflects the first part of this equation, but not the latter.

Q. What is your recommendation regarding the Company's proposal to increase O&M expense for projected CPI-based inflation?

A. The Adversary Staff recommends that the Commission reject this proposal. The Company's proposal is inconsistent with the Company's actual success in controlling O&M expense growth. It is inconsistent with the increase in national productivity that has outstripped inflation over the last five years. It is inconsistent with the Company including in rate base the cost of the investment in technology that it incurred to achieve those gains in productivity. It is inequitable to require that the ratepayers pay for the technology but not include the benefits of reduced O&M expense that were the very reason for the technology investment.

Q. Does your recommendation include any reduction in the Company's projections of test year benefits expenses?

A. No. We do not recommend any changes to the Company's requested O&M expense for pensions, other post-retirement benefits, or group insurance, including health insurance. The Adversary Staff recommended revenue requirement includes the full amount of the Company's proposed increases in these employee benefits expenses.

<u>AEC Operating Expense Amounts Allocated to Georgia Should Reflect Adversary Staff Recommendations on Affiliate Transactions and Cost Allocations</u>

Q. Have you reflected the changes to the AEC operating expense amounts allocated to Georgia consistent with the Adversary Staff recommendations on affiliate transactions and cost allocations?

A. Yes. These changes are reflected in the Adversary Staff revenue requirement recommendation in the Summary section of my testimony. AEC O&M expense and depreciation and other taxes expense allocated to Georgia has been reduced to reflect the Adversary Staff recommendations to 1) revise the AEC allocation factors to reflect known and measurable changes, 2) to correct the erroneous selection of AEC allocation factors, 3) to reflect known and measurable consolidation savings at the Mid-States Operating division, and 4) to remove the excessive AES expenses.

In addition, we have reflected the revenue requirement effect of the investment tax credit amortization expense allocated to Georgia. Finally, we have reflected the revenue requirement effect of Mr. King's recommended depreciation rates for the AEC Shared Services division and the effect on AEC Shared Services division depreciation expense allocated to Georgia, which has been adjusted to reflect the changes in the recommended composite allocation factor. The descriptions and computations of these amounts are detailed in the separate Panel Testimony of Ms. Taylor and Mr. Kollen on Affiliate Transactions and Cost Allocation issues.

V. BASE REVENUE REQUIREMENT - RATE OF RETURN ISSUES

Q. Have you quantified the effect of the Adversary Staff's recommendation to include short term debt in the capital structure compared to the Company's proposed hypothetical capital structure?

A. Yes. The Adversary Staff's recommendation to include short term debt in the capital structure reduces the Company's revenue requirement by $491,736. The Adversary Staff's recommended capital structure and cost of short term debt is discussed in the Panel Testimony of Victoria Taylor and Lane Kollen. The Adversary Staff's recommended rate base of $55, 796,961 was utilized for this quantification. The computations are detailed in Section II of my Exhibit___(LK-4).

Q. Have you quantified the effect of the Adversary Staff's recommended cost of long term debt?

A. Yes. The Adversary Staff's recommended cost of long term debt reduces the Company's revenue requirement by $30,631. This amount is in addition to the reduction in the revenue requirement due to incorporating short term debt in the capital structure. The Adversary Staff's recommended cost of long term debt is discussed in the Panel Testimony of Victoria Taylor and Lane Kollen. The computations are detailed in Section III of my Exhibit__(LK-4).

Q. Have you quantified the effect of Adversary Staff's recommended return on common equity?

A. Yes. The revenue requirement effect of the Adversary Staff's recommendation is $1,078,226. This amount is in addition to the reduction in the revenue requirement due to incorporating short term debt in the capital structure and correcting the Company's cost of long term debt. The Adversary Staff's recommended cost of common equity is discussed in Mr. Hill's testimony. The computations are detailed in Section IV of my Exhibit__(LK-4).

VI. EXPANDED REPORTING REQUIREMENTS

Q. Should the Commission expand the present periodic reporting to the Commission Staff?

A. Yes. The Company presently files an annual report in conjunction its PRP filing requirements established in Docket No. 12509-U. However, this annual report is not sufficiently detailed or sufficiently timely to meet the Staff's monitoring and review needs. The Company's present reporting requirements are substantially less than the AGLC's reporting requirements, which are contained in its monthly Grey Report.

The Adversary Staff recommends that the Company be required to file information in the quarterly reports broken out on a monthly basis, which would provide Commission Staff the opportunity to review all aspects of the Company's financial performance, including its earned return, on a timely basis. We recommend that these quarterly reports include the following information. In addition to the following information, we recommend that the Company provide the information outlined in the section on reporting requirements in the Panel Testimony of Victoria Taylor and Lane Kollen.

- Financial statements arranged by FERC account on a monthly and twelve month rolling basis that provide actual per books results with no ratemaking adjustments.

- Labor dollars incurred by department and by FERC account, separated between those labor dollars incurred directly by AEC Shared Services division, Mid-States Operating division, and Eastern Regional Office, which are allocated to Georgia, and amounts incurred directly by Georgia.

- A schedule detailing the various forms of capitalization with all monthly details provided to compute the actual weighted cost of capital for the thirteen month average period.

- Schedules detailing the various monthly rate of return components of rate base, operating income, the authorized cost of capital and the computation of the revenue requirement after ratemaking adjustments, on a twelve months ending basis. The rate base and operating income computations should reconcile the per books totals along with all ratemaking adjustments to arrive at the final results.

- A description and quantification of all monthly ratemaking adjustments based on the preceding thirteen month actual results.

- Full-time equivalent number of employees at month end for each month on a twelve month rolling basis for the Georgia division.

- Number of gas units and customers arranged by tariff schedule per month along with the corresponding revenues derived on a twelve-month rolling basis.

- Monthly uncollectible accounts expense activity that includes the beginning balance of uncollectibles reserve, expense accruals, charge-offs netted with recoveries, and the ending reserve balance on a twelve month rolling basis.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE: ATMOS ENERGY CORPORATION'S	)	
AFFILIATE TRANSACTION	)	DOCKET NO. 20298-U
AUDIT REVIEW/2005 RATE CASE	)	

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

GEORGIA PUBLIC SERVICE COMMISSION STAFF

SEPTEMBER 29, 2005

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than twenty-five years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of September 2005

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.

**Expert Testimony Appearances
of
Lane Kollen
As of September 2005**

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.

Expert Testimony Appearances
of
Lane Kollen
As of September 2005

Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170- EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171- EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.

Expert Testimony Appearances
of
Lane Kollen
As of September 2005

Date	Case	Jurisdict.	Party	Utility	Subject
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements , detailed investigation.

Expert Testimony Appearances
of
Lane Kollen
As of September 2005

Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

Expert Testimony Appearances of Lane Kollen As of September 2005

Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced	West Penn Power Co.	Incentive regulation,

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			Materials Co., The WPP Industrial Intervenors		performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.

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9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers mechanisms.	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery
4/99	99-02-05	CT	Connecticut Industrial Utility Customers mechanisms.	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative regulation.
6/99	97-596	ME	Maine Office of	Bangor Hydro-	Request for accounting

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Date	Case	Jurisdict.	Party	Utility	Subject
			Public Advocate	Electric Co.	order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement Stipulation.
7/99	97-596 (Surrebuttal)	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 (Surrebuttal)	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
8/99	98-474 98-083 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co. and Kentucky Utilities Co.	Alternative forms of regulation.
8/99	98-0452-E-GI (Rebuttal)	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 (Supplemental Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.

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07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 (Affidavit)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009		Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) (Surrebuttal)	LA	Louisiana Public Service Commission Staff f	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 (Direct)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925 and U-22092 (Subdocket B) (Surrebuttal)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc,.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.

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02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	PU, Inc. FirstEnergy	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution (Rebuttal)	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Review requirements, Rate Plan, fuel clause recovery.
11/01 (Direct)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.

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11/01 (Direct)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02 (Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02 (Rebuttal)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear llife extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02 (Supplemental Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092 (Subdocket C)		Louisiana Public Service Commission Staff	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission Statt	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

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04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KU	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.

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03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459, PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction
				true-up revenues, interest.	
08/04	SOAH Docket 473-04-4556 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	Docket No. U-23327 Subdocket B	LA	Louisiana Public Service Commission	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	Docket No. U-23327 Subdocket A	LA	Louisiana Public Service Commission	SWEPCO	Revenue requirements.

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As of September 2005

Date	Case	Jurisdict.	Party	Utility	Subject
12/04	Case No. 2004-00321 Case No. 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, etal.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
02/05	18638-U	GA	Georgia Public Service Commission	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and § 199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP System sales.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.

STF-S5-57 a. Please provide the revenues, expenses, and rate base components included in the Company's proposed base revenue requirement that are related to the costs presently recovered through the PRP Rider.

b. Provide all supporting workpapers, assumptions, data, and computations, including electronic spreadsheets with cell formulas intact.

STF-5-57 requested that the Company separately quantify all PRP rate base, revenue, and expense components from the base rate components in its filing. The Company's response provided the computation of the present PRP surcharge based on a fiscal year 2003 test year, not the amounts in the Company's filing for the projected test year. The Company acknowledged in response to STF-5-62 that the roll-in reflected in the filing reflected "the average level of investment in the projected test year ended June 19, 2006." Please provide the information requested in STF-5-57.

Response:

The average level of investment in the projected test year ended June 19, 2006 that is related to the pipe replacement program is calculated in the attached spreadsheet. Since the projected test year crosses fiscal years 2005 and 2006, the calculation uses the projected surcharge calculation for 2005 and 2006 from the response to STF 5-60. The test year calculation is a weighted average of 8 months in fiscal 2006 and 4 months in fiscal 2005. The rate of return on capital investment and the depreciation rates used in the test year calculation are the rates proposed by the Company. Please also see attached.

Respondent: Mr. Petersen

Atmos Energy Corporation

Georgia Distribution System

Surcharge Calculation for Activity through September 2004

Cast Iron & Bare Steel Pipe Replacement Program

Monthly Customer Surcharge

Page 1

Item # 11.

Description	Year ended 30-Sep-04	Year ended 30-Sep-05	Year ended 30-Sep-06	TY ended 19-Jun-06
Cast Iron Additions to Gross Plant	$ 8,543,298	$ 11,016,688	$ 16,429,418	$ 14,625,175
Bare Steel Additions to Gross Plant	1,313,160	1,918,179	2,523,199	$ 2,321,525
Cast Iron Retirements from Gross Plant	(1,383,610)	(1,737,350)	(2,356,291)	$ (2,149,977)
Bare Steel Retirements from Gross Plant	(267,876)	(390,402)	(512,928)	$ (472,086)
Net Change to Gross Plant	$ 8,204,971	$ 10,807,116	$ 16,083,398	$ 14,324,638
Cast Iron Cost of Removal to Accum. Depre.	98,787	124,043	168,234	153,504
Bare Steel Cost of Removal to Accum. Depre.	248	362	475	437
Cast Iron Retirements from Accum. Depre.	1,383,610	1,737,350	2,356,291	2,149,977
Bare Steel Retirements from Accum. Depre.	267,876	390,402	512,928	472,086
Depreciation Accrual to Accum. Depre.	(313,738)	(548,488)	(325,207)	(399,634)
Net Change to Net Plant	$ 9,641,755	$ 12,510,784	$ 18,796,120	$ 16,701,008
Deferred Taxes	(326,410)	(541,436)	(1,053,707)	(882,950)
Net Change to Capital Investment	$ 9,315,345	$ 11,969,348	$ 17,742,412	$ 15,818,058
Rate of Return (grossed up for taxes)	12.84%	12.84%	12.84%	12.656%
Return on Capital Investment	$ 1,196,277	$ 1,537,104	$ 2,278,481	$ 2,001,933
Annual Depreciation Expense [1]	203,368	266,132	384,281	354,651
Removal of Gainesville amount	(90,000)	(90,000)	(90,000)	(90,000)
True up from prior year with carrying charges	9,913	-	-	-
Estimated Annual O&M Savings	(141,010)	(178,194)	(214,626)	(202,482)
Revenue Requirement (before revenue taxes)	$ 1,178,549	$ 1,535,042	$ 2,358,136	$ 2,064,103
Revenue Tax Rate	3%	3%	3%	3%
Total Revenue Requirement	$ 1,214,999	$ 1,582,518	$ 2,431,068	$ 2,127,941
Average Number of Customers	780,407	780,407	780,407	
Monthly Customer Surcharge	$ 1.56	$ 2.03	$ 3.12	

[1] Depreciation expense for the test year ended June 19, 2006 calculated at proposed depreciation rates.

Atmos Energy Corporation
Georgia Distribution System
Surcharge Calculation for Activity through September 2004
Cast Iron & Bare Steel Pipe Replacement Program
Depreciation Expense

Page 2

Description	Mains	Services	Meter Loops	Total
	(Acct 376)	(Acct 380)	(Acct 381)	
Net Change to Gross Plant	$ 6,350,224	$ 1,749,926	$ 104,821	
Depreciation Rates	2.04%	4.03%	3.15%	
Annual Depreciation Expense	$ 129,545	$ 70,522	$ 3,302	$ 203,368
Current Year Changes to Net Plant	2,381,126	849,158	51,655	
Depreciation Rates	2.04%	4.03%	3.15%	
Annual Depreciation Expense	$ 48,575	$ 34,221	$ 1,627	$ 84,423
Accumulated Depreciation from Prior Year				$ 152,581
Accumulated Depreciation Current Year - Prior Additions				118,945
Accumulated Depreciation Current Year - Current Additions				42,212
				$ 313,738
Projected Depreciation Expense				
2005 at current depreciation rates	$ 172,705	$ 90,126	$ 3,302	$ 266,132
2006 at current depreciation rates	$ 269,565	$ 111,414	$ 3,302	$ 384,281
2005 net change to gross plant	8,465,925	2,236,370	104,821	$ 10,807,116
2006 net change to gross plant	13,213,959	2,764,619	104,821	$ 16,083,398
Proposed new depreciation rates	2.41%	2.79%	2.02%	
2005 at proposed depreciation rates	204,029	62,395	2,117	$ 268,541
2006 at proposed depreciation rates	318,456	77,133	2,117	$ 397,707
Test year ended June 19, 2006 weighted average				354,651

Atmos Energy Corporation
Georgia Division
Response to Staff Fifth Data Requests
Docket 20298-U

STF-5-13 Please provide a description of all technology initiatives implemented in the last two years or projected to be implemented by the end of the projected test year by Atmos Energy Corp. Shared Services, Mid-States Division, or the Eastern Regional Division, such as the implementation of new systems and/or software and/or capital investments, that were undertaken to improve productivity and/or reduce costs. For each such initiative undertaken, please provide a copy of the capital expenditure authorization request and the underlying economic analyses, such as cost-benefit studies.

Response:

Year Business Unit	**Capital Project**	**Description**	**Cost**	**Projected Benefits**
2004 & 2005 Shared Services	Establish always on connection for service technician truck mounted mobile data terminals	Installed satellite modems for service technicians servicing geographically remote areas without access to cellular data services. Prior to this service technicians were unable to receive orders (including emergency orders) and/or update order status electronically without driving back to a metropolitan area where cellular data service was available. This delayed their ability to provide timely customer service.	$332,950 FY04 $257,711 FY05	Improved customer service & faster response to emergency calls

Atmos Energy Corporation
Georgia Division
Response to Staff Fifth Data Requests
Docket 20298-U

2004 Shared Services	New compliance asset management system	New system to automate the scheduling & reporting for regulatory compliance activities including periodic leak surveys and follow up inspections; odorizer tests; odor sampling; cathodic protection test points; interference bonds; casing, insulator, rectifier, pipeline, regulator, and valve inspections; first response training; and contractor awareness.	$4,099,107	Improved regulatory compliance and regulatory reporting.
2004 Mid States Division	Personal computer replacements	Periodic replacement of desktop personal computers	$281,890	Improved performance for new computer applications.
2004 Shared Services	Automated invoice processing system	Packaged software to automate the receipt; routing, approval, and payment of invoices.	$623,375	Streamlined invoice processing resulting in more timely and accurate payments to suppliers and improved expense reporting to State Regulators

2004 Shared Services	Margin Analysis and Reporting Tool (MART).	A repository of transaction billing data with a front end reporting tool to enable margin analysis, by service class at the total company, business division and town levels.	$2,591,003	Improved margin analysis and reporting and faster month-end financial closing.
2004 Shared Services	Lost and Unaccounted for (L&U) Gas reporting system	Replaced a distributed spreadsheet based process with an in-house developed Oracle system with distributed and centralized monitoring and control capability.	$122,221	Improved monitoring and reporting for L&U.
2005 Shared Services	Upgrade to customer billing system	Upgrade to the latest software version of our customer billing software. This is the first upgrade since the billing system was implemented 9 years ago.	$17,000,000	Increased functionality. Improved customer service. Vanilla package in lieu of heavily customized software currently in use.
2005 Shared Services	New Accounts Receivable Module	Replacement for homegrown system to process billing for third party damages and local office billings.	$100,000	Better accounting and collections for third party damages.
2005 Shared Services	Plant Accounting System	Implemented a new plant accounting system.	$1,205,189	Enables the application of blended shared service depreciation rates by rate jurisdiction as

				well as improves the quality and accuracy of plant accounting information.
Projected 2006 Shared Services	Construction asset management system	New system that automates the previously manual, fragmented construction management and accounting process. Includes a common project estimation module (for more consistent estimation across the total company. Automates the entire construction process from project estimation to project approval(s) to scheduling of people, equipment, and materials to generating a purchase order to have materials drop shipped directly to the construction site, to automated posting of labor and other expenses for CWIP to project completion and asset generation.	$3,487,392	Streamlined construction process and more timely and more accurate accounting for capital projects and work in progress.

Please see the attached approval forms. The projects listed are improvements, upgrades or the replacement of existing systems. No cost-benefit analyses were performed for these projects.

Respondent: Les Duncan
Vice President & CIO

Name of Project : Satellite Modems for the non-Mid-Tex Divisions **Date:** 1/3/2005

Cost Ctr Number/Name: 1137 - Dallas Data Center

PROJECT DESCRIPTION: Purchase Satellite Modems for the divisions that will be implementing them this Fiscal Year other than those being purchase for Mid-Tex.

Task Number		Div. Ovh	Cost	Overhead *	Total	Project #
39903	Sat'lite Modems	0.00%	$256,000	$50,458	$306,458	
	Totals:		$256,000	$50,458	**$306,458**	

Budget Request # CB.010.10xxx

19.71% *Overhead percentage used.

Estimated Project Cost: $306,458

PROJECT MANAGER: Will Nall

APPROVALS:

Initiator: Will Nall 1/3/2005

Comments

Recommend Approval: Ron Acker Date: 1/3/2005

Comments Included in the most recent approved budget.

Recommend Approval: Les Duncan Date: 1/3/2005

Comments

FINAL APPROVAL John P. Reddy Date: 1/3/2005

Comments

PURPOSE AND NECESSITY

Name of Project : AP Invoice Imaging with 170 Systems Markview **Date:** 10/30/2003

Cost Ctr Number/Name: 1134 IT Management

PROJECT DESCRIPTION: Install AP imaging software for automated on-line routing and approval.

Task Number		Project #
39908	Application Software Development	456,165
39901	Servers/Hardware	100,000
OVRHD	Overhead	99,165

Estimated Project Cost: $ 655,330.00

PROJECT MANAGER: Paul Watkins

APPROVALS:

Initiator: Paul Watkins 10/30/2003

Comments Please approve for purchase of Software and Hardware

Recommend Approval: Jerry Malone Date: 11/12/2003

Comments Recommend approval of this budgeted item.

Recommend Approval: ____________ Date: ________

Comments

Recommend Approval : ____________ Date: ________

Comments

Recommend Approval : ____________ Date: ________

Comments

Recommend Approval : ____________ Date: ________

Name of Project : Gas Accounting Data Mart **Date:** 11/12/2003

Cost Ctr Number/Name: 1134-Information Technology Management

Was this project budgeted in PlanIt? YES

PROJECT DESCRIPTION: Develop a Gas Accounting data mart with a Hyperion reporting frontend.

Task Number		Project #
39908		
Develop a Gas Accounting data mart with a Hyperion reporting frontend.	448,679	
39901		
Hardware	100,000	
Overhead	97,830	
Total	646,509	

Estimated Project Cost: $ 646,509.00

PROJECT MANAGER: Jerry Malone

APPROVALS:

Initiator: Jerry Malone 11/12/2003

Comments Les, Your approval for this budgeted project is requested. Thanks, jm

Recommend Approval: ____________ Date: ________

Comments ____________

Recommend Approval: ____________ Date: ________

Comments ____________

Recommend Approval : ____________ Date: ________

Comments ____________

Recommend Approval : ____________ Date: ________

Comments ____________

Recommend Approval : ____________ Date: ________

Name of Project : Lost & Unaccounted Gas System **Date:** 11/3/2003

Cost Ctr Number/Name: 1134-Information Technology Management

Was this project budgeted in PlanIt? YES

PROJECT DESCRIPTION: Develop an automated 12 month average L&U system

Task Number		Project #
39908	$499,208	
39901	$100,000	
Total	$599,208	
Overhead	$106,839	
Total Cost	$706,047	

Estimated Project Cost: $706,048

PROJECT MANAGER: Jerry Malone

APPROVALS:

Initiator: Jerry Malone 11/3/2003

Comments Les, For your review and approval. Thanks, jm

Recommend Approval: Date:

Comments

Recommend Approval: Date:

Comments

Recommend Approval : Date:

Comments

Recommend Approval : Date:

Comments

Recommend Approval : Date:

STF-5-13

PURPOSE AND NECESSITY

Name of Project : Plant System - Power Plant **Date:** 7/31/2004

Cost Ctr Number/Name: 1134 - I T Management

Was this project budgeted in PlanIt? YES ______ NO X

PROJECT DESCRIPTION: Convert plant system from Oracle to Power Plant. **PROJECT NUMBER:** 10.10972

Description	Hardware	Software	Consulting	Internal Labor	Total
Windows NT Server	35,000				35,000
2 Power Builder Licenses	5,000				5,000
Asset Management		262,500	150,500		413,000
CR - Basic Integration		56,250	53,750		110,000
Projects - CWIP Accounting		56,250	32,250		88,500
Projects - Unitization		112,500	64,500		177,000
TXU Integration			64,500		64,500
2 Plant Accountants				150,000	150,000
1 IT Specialist				75,000	75,000
Training Costs				0	0
Subtotal	40,000	487,500	365,500	225,000	1,118,000
Labor Overhead (33.67%)				75,758	1,193,758
Corporate Overhead (17.83%)					212,847
Total Cost					1,406,604

Project #	Task Number	Total
	39901 - Servers Hardware	
	39908 - Applications Software	1,406,604

PROJECT MANAGER:

APPROVALS:

Initiator: Martha McGuire, Manager of Plant Accounting 7/30/2004

Comments This system will enable us to apply blended depreciation rates which will result in the ability to apply approved rates per division to depr exp on shared services allocated to each division.

Consulting fees based on estimate of 140 man-days at $2,150 per day.
Software includes a discount of 25% off retail price due to "medium" company size. (Discount locked in prior to TXU acquisition - after which Atmos will become a "large" company and would not have qualified for any discount on Power Plant.)

Recommend Approval: Jerry Malone Date: 8/17/2004
Comments Les, for your review and approval .

Recommend Approval: ______ Date: ______
Comments

Recommend Approval : ______ Date: ______
Comments

FINAL APPROVAL ______ Date: ______
Comments

Name of Project : Oracle Accounts Receivable Implementation **Date:** March 1,2005

Cost Ctr Number/Name: 1135-Information Systems Support

Was this project budgeted in PlanIt? NO

PROJECT DESCRIPTION: Configure and implement Oracle's Accounts Receivable

Task Number			Project #
39908			
Contract labor		69,000	
Atmos Labor		30,000	
		99,000	
Overhead @	19.71%	19,513	
Total		118,513	

Estimated Project Cost: $ 118,513.00

PROJECT MANAGER:

APPROVALS:

Initiator: Jerry Malone 3/1/2005

Comments Please review and approve this request to implement Oracle's AR module for Mid-Tex's LOB and TBS invoicing. Thanks, jm

Recommend Approval: Dan Meziere Date: 3/3/2005

Comments

Recommend Approval: Les Duncan Date: 3/3/2005

Comments

Recommend Approval : Date:

Comments

Recommend Approval : Date:

Comments

Recommend Approval : Date:

Comments

Recommend Approval : Date:

Comments

FINAL APPROVAL John P. Reddy Date: 3/4/2005

Comments

Name of Project : Oracle Enterprise Management System **Date:** 10/6/2003

Cost Ctr Number/Name: 1134-IT Management

PROJECT DESCRIPTION: Oracle eAM Phase I--Maintenance

Task Number		**Project #**
39908		

Oracle eAM License	$567,988
Oracle Consulting	$531,524
Total	$1,099,512
O-H @ 17.20%	$189,116
	$1,288,628

This request represents one half of the cost of the eAM license and Oracle Consulting implementation fees.
The balance will be paid in FY '05.

Estimated Project Cost: $1,288,628

PROJECT MANAGER: Jerry Malone

APPROVALS:

Initiator: Jerry Malone 10/6/2003

Comments Les, submitted for your approval.

Recommend Approval: ______ Date: ______

Comments

Recommend Approval: ______ Date: ______

Comments

Recommend Approval : ______ Date: ______

Comments

Recommend Approval : ______ Date: ______

Comments

Recommend Approval : ______ Date: ______

ATMOS COST OF CAPITAL
TEST YEAR ENDING JUNE 19, 2006

I. Atmos Cost of Capital Per Filing

	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	0.00%	0.00%	0.0000%	0.0000%
Long Term Debt	50.00%	5.67%	2.8358%	2.8358%
Common Equity	50.00%	12.00%	6.0000%	9.8200%
Total Capital	100.00%		8.8358%	12.6558%

II. Atmos Cost of Capital Adjusted to Include Short Term Debt

	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	10.00%	3.85%	0.3850%	0.3850%
Long Term Debt	45.00%	5.67%	2.5515%	2.5515%
Common Equity	45.00%	12.000%	5.4000%	8.8380%
Total Capital	100.00%		8.3365%	11.7745%

.8813%
55,796,961
491,736

III. Atmos Cost of Capital Adjusted to Include STD and Revise LTD Rates

	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	10.00%	3.85%	0.3850%	0.3850%
Long Term Debt	45.00%	5.55%	2.4966%	2.4966%
Common Equity	45.00%	12.000%	5.4000%	8.8380%
Total Capital	100.00%		8.2816%	11.7196%

.0549
55,796,961
30,631

IV Atmos Cost of Capital Adjusted to Include STD, Revise LTD Rates, Adversary Staff ROE

	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	10.00%	3.85%	0.3850%	0.3850%
Long Term Debt	45.00%	5.55%	2.4975%	2.4975%
Common Equity	45.00%	9.375%	4.2188%	6.9047%
Total Capital	100.00%		7.1013%	9.7872%

1.9324
55,796,961